TECHNICAL REVIEW DOCUMENT (TRD)
for
RENEWAL of OPERATING PERMIT 95OPEP106

Colorado Springs Utilities – Ray D. Nixon Power Plant

El Paso County
Source ID 0410030

November 2009, March – May 2012

Operating Permit Engineer: Bailey Kai Smith and Matthew S. Burgett
Operating Permit Supervisor review: Matthew S. Burgett
Field Services Unit review: Dave Huber
Permitting Manager review: Roland Hea

I. Purpose:

This document will establish the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewed operating permit proposed for this site. The original Operating Permit was issued July 1, 2002, and expired on July 1, 2007. This document is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the renewal application submitted June 30, 2006, the modification application submitted February 27, 2009, additional technical information submitted, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division website at http://www.cdphe.state.co.us/ap/Titlev.html.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised Construction Permit.

II. Description of Source

This facility is an electric generation utility classified under the Standard Industrial Classification code 4911. The Nixon Power Plant consists of one steam driven electrical generating unit and the associated equipment (turbine-generators and cooling towers), two natural gas fired simple cycle combustion turbines driving electricity generators, and one natural gas/fuel oil fired auxiliary boiler, along with equipment associated with coal and flyash handling. The facility also includes the adjacent Front Range Power Plant (FRPP) which consists of two natural gas fired combined cycle combustion turbines, two heat recovery steam generators with duct burners, and one steam turbine.

This plant is located in Colorado Springs, Colorado. The area in which the plant operates is classified as attainment for all criteria pollutants. There are no affected states within 50 miles of the plant. There are no Federal Class I designated areas within 100 kilometers of the facility. Florissant Fossil Beds National Monument is a Federal land area within 100 kilometers of the facility. Florissant Fossil Beds has been designated by the State to have the same sulfur dioxide increment as a Federal Class I area.

Based on information supplied by the permit applicant, the facility is subject to the requirements of Section 112(r)(7), the Accidental Release Plan Program of the Clean Air Act. The coal fired boiler and two simple cycle combustion turbines at Nixon and the two combined cycle combustion turbines at FRPP are electric generating units subject to the requirements of Title IV, the Acid Rain Program.

This source is considered to be a major source for particulate matter (PM & PM_{10}), nitrogen oxides (NO_X), sulfur dioxides (SO_2) and carbon monoxide (CO) in an attainment area (Potential to Emit > 250 Tons Per Year). In addition, B001 is considered a major source (PTE > 100 TPY) for the source category “Fossil fuel-fired steam electric plants of more than 250 million Btu/hr heat input”. B001 commenced construction prior to the effective date of the Prevention of Significant Deterioration (PSD) regulations on June 1, 1975, and the adoption of the regulations implementing the Clean Air Act Amendments of 1977 on August 7, 1980. Thus, B001 was not required to conduct PSD review or install Best Available Control Technology (BACT).

For purposes of determining applicability of PSD regulations, Clear Springs Ranch –Solids Handling and Disposal Facility (96OPEP152) is considered a single source with the Nixon/FRPP facility.

In general, equipment (including boilers burning fossil fuel containing sulfur) are subject to the Colorado Regulation No. 1 and No. 6 standards for SO_2. B001 was installed prior to the applicability date (January 30, 1979) for the Regulation No. 6 SO_2 standard (Reg. 6, Part B.II). Therefore, no specific Regulation No. 6, Part B SO_2 limitations were included in the renewed operating permit for B001.

Facility-wide emissions are outlined below:

Pollutant	Potential-to-Emit (tons/yr)	Actual Emissions – 2008 (tons/yr)
PM_{10}	1223	152.6
PM	1255	124.1
SO_2	10572	447.4
NO_X	3652	2854.5
VOC	74.2	35.8
CO	724	333.3
HAPs	>25	41.8

Potential emission estimates are based on information provided by the applicant. Actual emissions are based on recent APENs submitted and represent the year 2008 emissions. Please note that the majority of these CO emissions are from B001, and were historically calculated based upon the AP-42 emissions factor. However more recently CSU has been collecting and reporting CO emissions based on CEMS measurements, which has shown the AP-42 factor based emissions to be comparatively understated for B001.

Greenhouse Gases

This facility's potential to emit greenhouse gases exceeds 100,000 tons CO_2e per year. Future modifications at this facility will have to be evaluated to determine whether GHG emissions are subject to regulation.

NESHAP Applicability

This facility is considered a major source of Hazardous Air Pollutants (HAPs).

Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters: The auxiliary boiler, Unit B001, is subject to the requirements for industrial boilers at major sources of HAPs. Since the rule was initially promulgated in 2004, several proposed amendments and reconsiderations have. A new final rule was published in the Federal Register on January 31, 2013. The source requested these requirements be incorporated into the permit during the public comment review period. The source requested a federally enforceable limitation on the unit's capacity to qualify as a limited-use boiler. This limitation was created in the form of a fuel use annual limitation. As a limited-use boiler, the unit is subject to the periodic tune-up provisions and reporting requirements. The appropriate applicable requirements were included in the operating permit.

Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines: All four turbines are considered to be existing (commenced construction prior to January 14, 2003) and do not have to meet the requirements of this subpart and of subpart A of part 63. No initial notification is necessary. (Reference §63.6090(b)(4))

Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines: Three emergency engines exist at the Nixon facility, one emergency diesel-fired generator (449 hp) and two emergency diesel-fired fire pumps (218 hp and 170 hp, respectively).

The initial RICE MACT was published in the Federal Register on June 15, 2004 and the requirements applied to new and existing engines 500 hp or greater located at major sources of HAPs. Under the initial rules, existing emergency engines located at major sources of HAPs were not subject to any requirements (including initial notification) per 63.6590(b)(3).

Revisions to the RICE MACT were published in the Federal Register on January 18, 2008 to address new (constructed after June 12, 2006) engines 500 hp or less located at major sources. Under these revisions, existing compression ignition (CI) engines, 2-stroke lean burn (2SLB) and 4-stroke lean burn (4SLB) engines were not subject to any requirements in either Subparts A or ZZZZ (40 CFR Part 63 Subpart ZZZZ § 63.6590(b)(3)). Further revisions to the RICE MACT were published in the Federal Register on May 3, 2010 to address existing (constructed prior to June 12, 2006) CI engines, including emergency engines, 500 hp or less located at major sources.

The three emergency engines were placed in service prior to June 12, 2006 and are therefore considered existing engines under the rule. As provided for in § 63.6602, existing emergency engines 500 hp or less located at a major source are subject to management practice requirements to regularly perform inspections and maintenance activities.

Under the “catch-all” provisions in Regulation No. 3, Part C, Section II.E, sources that are subject to any federal or state applicable requirement, such as National Emission Standards for Hazardous Air Pollutants (NESHAPs), may not be considered insignificant activities for operating permit purposes. Although the unit cannot be considered insignificant activity, since the Division has not yet adopted the RICE MACT provisions which address these sources, the emergency engines are still exempt from APEN reporting and minor source construction permit requirements.

Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-fired Electric Utility Steam Generating Units: The final MACT requirements for electric utility steam generating units were promulgated on February 16, 2012. B001 qualifies as an existing unit under these requirements and therefore will have three years to comply with the MACT requirements, pending any extensions or subsequent regulatory actions. Under the final rule, B001 will be subject to emission limitations for filterable PM (or total non-Hg HAPS or individual non-Hg HAPS), HCl (or SO_2) and Hg. Several compliance options are offered for the various pollutants including provisions for low emitting units and emissions averaging for units within the same subcategory, located at a single source. Given the number of compliance options and the fact that existing sources will have three years to comply with the requirements, the permit includes a requirement to submit an application to modify the Title V permit within one year after the compliance date to incorporate the chosen compliance options into the permit.

<u>Federal Clean Air Mercury Rule Requirements</u>

The EPA published final rules to address mercury emissions from coal-fired electric steam generating units on March 15, 2005. These rules are referred to as the Clean Air Mercury Rule (CAMR), which required mercury standards for new and modified emission units and provided a trading program for existing units. Under this program, sources would be required to get a permit (application due date July 10, 2008) and to meet monitoring system requirements (install and conduct certification testing) by January 1, 2009.

However, on February 8, 2008 a DC Circuit Court vacated the CAMR regulations for both new and existing units. Therefore, the federal CAMR requirements are not in effect, as of the issuance of this renewal permit.

<u>State Clean Air Mercury Rule Requirements</u>

Although the Division did adopt provisions from the federal CAMR rule into our Colorado Regulation No. 6, Part A, the Division also adopted State-only mercury requirements in Colorado Regulation No. 6, Part B, Section VIII. As discussed above, the provisions from the federal CAMR rule have been vacated and are no longer applicable. While the state-only mercury requirements rely in some part of the federal CAMR rule, there are emission limitations and permit requirements that do not rely on the federal rule and are still in effect. In addition, on November 20, 2008, the Colorado Air Quality Control Commissions (AQCC) adopted into Reg 6, Part B, Section VIII, the monitoring, recordkeeping and reporting requirements in the vacated CAMR rule. The revisions to Reg 6, Part B took effect on December 30, 2008.

Currently, Unit B001 is considered a Low Emitter, as actual Hg emissions are less than 29 pounds per year. B001 must be routinely tested to maintain its status as a Low Emitter. The Regulation No. 6 definition of Low Emitter outlines the testing schedule as an annual performance test if actual emissions are less than or equal to 14 pounds per year and a semi-annual performance test if actual emissions are greater than 14 pounds per year, but less than or equal to 29 pounds per year. The source must also report Hg emissions on a quarterly basis

The Low Emitter provisions found in Regulation No. 6 Section VIII are applicable requirements and have been incorporated into the permit for B001. The source was required to submit a complete permit application to the Division to incorporate the applicable requirements of Regulation No. 6, Section VIII by July 1, 2012. This application has been received by the Division prior to July 1, 2012.

NSPS Applicability

Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971. Requirements are listed in Section II.1.6 of the renewal permit for B001. Requirements include limitations on emissions of PM, SO_2, NO_X, and opacity. Opacity is monitored with a Continuous Opacity Monitoring System (COMS). NO_X and SO_2 are monitored with a Continuous Emissions Monitoring System (CEMS).

Subpart D & Db – These requirements do not apply to B002 since the design heat input rate is less than 100 mmBtu/hr. The heat recovery steam generators with duct burners are not subject to the requirements of these subparts since they are subject to Subpart Da.

Subpart Da – Standards of Performance for Electric Utility Steam Generating Units. The two heat recovery steam generators with duct burners are subject to this subpart. Requirements include limitations on emissions of PM, SO_2, NO_X, and opacity. Compliance with the PM, SO2, and opacity limitations are presumed given only natural gas is permitted to be used a fuel in the units. NO_X is monitored with a CEMS.

Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. This subpart does not apply to B002 since construction commenced prior to June 9, 1989.

Subpart Y – Standards of Performance for Coal Preparation and Processing Plants. This subpart applies to some of the coal processing equipment as outlined in Section II.3 of the renewal permit. This equipment must comply with the 20% opacity limitation.

The requirements of this rule were modified on October 8, 2009. If the open storage pile, which includes the equipment used in the loading, unloading, and conveying operations of the affected facility, is constructed, reconstructed, or modified after May 27, 2009, the permittee must prepare and operate in accordance with a submitted fugitive coal dust emissions control plan that is appropriate for the site conditions. Since the open coal storage pile has not been modified, a fugitive coal dust emissions control plan is not required at this time.

Subpart GG – Standards of Performance for Stationary Gas Turbines. The two simple cycle combustion turbines at Nixon as well as the two combined cycle combustion turbines at FRPP are subject to this rule. The requirements are included in the renewal permit in Section II.7. Requirements include NO_X and SO_2 emission limitations and monitoring of the fuel for sulfur content.

RACT Applicability

Reasonably Available Control Technology (RACT) requirements do not apply since the potentially applicable minor units commenced construction prior to the RACT requirement appearing in Regulation No. 3 on June 30, 1980. (Regulation No. 3, Part B, III.D.2). Additionally, all equipment at this facility is located in an area currently designated as attainment for all pollutants.

BART Applicability

An analysis was conducted to determine if these units were eligible to the Best Available Retrofit Technology (BART) requirements of 40 CFR Part 51. The boiler does fall within the BART category of "Fossil-fuel fired steam electric plants of more than 250 million BTU per hour heat input" and is BART-eligible.

Colorado Springs Utilities (CSU) submitted emission rates of NO_X & SO_2 from the BART-eligible boiler, B001, on June 30, 2006. The emission rates were based on historic data from the Continuous Emission Monitoring System (CEMS). According to an October 30, 2006 APCD document, CSU has passed the BART modeling and a full BART analysis is not required at this time. The modeled impact is 0.481 dv.

Unit B001 is subject to the reasonable progress (RP) limits in Colorado Regulation No. 3, Part F, Section VI.B. The Regional Haze Plan was given final approval by the U.S. EPA on September 10, 2012. The approval has yet to be published in the Federal Register and will become effective 30 days after publication. Reasonable Progress for the CSU Nixon boiler was determined to be short term (30-day averages) emission limitations for NO_X and SO_2 as well as a particulate emission limit. The source must submit a compliance plan to the Division within 60 days of publication of EPA's final approval of the SIP in the Federal Register.

Compliance Assurance Monitoring (CAM) Applicability

CAM plans are generally required for emission units that use a control device to meet an emission limitation or standard and has pre-control device emissions above the major source levels. A CAM plan was submitted for B001 and will be discussed later in this document. None of the other emission units are required to obtain a CAM plan as discussed below.

No control device

The following sources/activities are not subject to CAM since they do not utilize a control device to reduce emissions: auxiliary boiler, simple cycle combustion turbines, cooling tower, ash haul roads, ash disposal operations, coal stockpile, and FRPP combined cycle turbines.

The coal stockpile and ash disposal/hauling does require watering as a control measure to reduce particulate emissions and opacity. However, the Division does not believe water application meets the definition of control equipment in the CAM rule. The preamble to the CAM rule provides more insight into the control technology definition and provides the following (from October 22, 1997

Federal Register, page 54912, 3rd column, under *control devices criterion*)

> The final rule provides a definition of "control device" that reflects the focus of Part 64 on those types of control devices that are usually considered as "add-on" controls." This definition does not encompass all conceivable control approaches but rather those types of control devices that may be prone to upset and malfunction, and that are most likely to benefit from monitoring of critical parameters to assure that they continue to function properly. In addition, a regulatory obligation to monitor control devices is appropriate because these devices generally are not a part of the source's process and may not be watched as closely as devices that have a direct bearing on the efficiency or productivity of the source.

The Division considers that the use of water application to reduce fugitive and/or visible emissions is not considered an add-on control device and is not the type of device that would benefit from monitoring critical parameters. Therefore, the Division determined that based on the specific provisions in the CAM requirements that fugitive emissions from coal stockpiles and ash hauling/disposal are uncontrolled activities for CAM purposes and do not require CAM plans.

Pre-control emissions below the major source level
The following sources/activities are identified as units with pre-controlled emissions below the major source level and therefore not subject to CAM: the coal handling systems (point sources), coal crusher, and the flyash silos. The Division has determined that using the uncontrolled emission factor(s) and permitted processing rate(s) that emissions from these sources/activities are below the major source level.

III. Discussion of Modifications Made

Based on the information provided in the June 30, 2006 renewal application, the following changes have been requested by Colorado Springs Utilities (CSU):

- Update the responsible official and facility contact person.
- Modification of the CAM language.
- Update the H_2SO_4 emission factor.
- Removal of specification used oil as a permitted fuel.
- B002: Removal of the PM short-term limitation.
- B002: Modification of the opacity requirements.
- B002: Removal of the SO_2 short-term limitation.
- P202: Modification of the opacity language.
- P202: Removal of (previous) Condition 3.5.
- P201: Removal of the monthly limitations.

- S003, S004: Modification of BACT limitation.
- Modification of the fuel sampling plan.
- Update the Acid Rain allowances.
- B001 CAM Plan submitted.

In addition to the renewal application, CSU has requested the following:

- In a modification application received February 27, 2009, CSU requested to add the SO_2 emission limitation from construction permit 10EP325 into the Operating Permit.
- An administrative amendment request was submitted on February 1, 2010 to update the responsible official.
- In comments on the predraft permit, received on March 3, 2010, CSU requested an alternative BACT limit for combustion tuning and testing.
- In letters dated November 23, 2010 and March 25, 2011, CSU requested clarification on the burning woody biomass as fuel.
- A transfer of ownership was received for the FRPP turbines on January 20, 2011. A complete Title V application for the turbines was received November 21, 2003. CSU has requested the turbines be rolled into the Nixon permit renewal.

Source Requested Modifications

The permit contact information has been updated.

CSU requested that the Division modify the CAM language in Section I.5 to clarify when CAM requirements apply. This is not necessary since the Division is incorporating the CAM requirements of B001 into this renewal permit. Standard Division language will be used.

CSU requested that the Division update the H_2SO_4 emission factor listed in the permit to match the emission factor derived from recent stack testing. The Division reviewed the language and has decided to remove the emission factor from the permit. It is not common practice for the Division to list the emission factors for HAPs in the Operating Permit.

CSU requested that the Division remove from the permit references to specification used oil. CSU does not store or use specification used oil at this point. The Division has removed all references to specification used oil from the permit. Specification used oil shall no longer be used as fuel at the Nixon plant.

CSU requested that the Division remove the short term PM limit from the B002 requirements. This limit is derived from Regulation No. 1, Section III.A.1.b and continues to be an applicable requirement. As such, the Division will include it as a permit requirement. However, compliance may be demonstrated by maintaining a record of calculation demonstrating the combination of the emission factor and fuel heat content precludes non-compliance. The Division has removed the requirement to conduct specific monthly calculations to demonstrate compliance. This is no longer necessary based on the removal of specification used oil as a permitted fuel.

CSU requested that the Division modify the B002 opacity monitoring requirements to clarify that compliance with the opacity limit shall be presumed whenever natural gas is the only fuel being used. The Division agrees and has made the requested language changes to be consistent with other permit language/requirements.

CSU requested that the Division remove the short term SO_2 limit from the B002 requirements. This limit is derived from Regulation No. 1, Section VI.B.4.b(i) and continues to be an applicable requirement. As such, the Division will include it as a permit requirement. However, compliance may be demonstrated by maintaining a record of calculation demonstrating the combination of the emission factor and fuel heat content precludes non-compliance. The Division has removed the requirement to conduct specific monthly calculations to demonstrate compliance. This is no longer necessary based on the removal of specification used oil as a permitted fuel.

CSU requested that the Division modify the Coal Handling opacity requirements to include the following language:

> All Method 9 opacity observations shall be performed by a certified observer. A clear and readable copy of the observer's certificate and any opacity observations shall be kept on file and made available to the Division for review upon request.

The Division has added this language to the Coal Handling opacity requirements of the renewal Operating Permit.

CSU requested that the Division remove condition 3.5 of the original operating permit. The Division reviewed this requirement and determined that the requirement was nearly identical to the opacity requirement under condition 3.3 of the original Operating Permit. The Division has included an opacity requirement for all the coal handling sources under condition 3.4 of the renewal Operating Permit and removed the duplicative requirements. This requirement applies to all coal handling sources including the stockpile. The opacity monitoring requirements essentially remain the same.

CSU requested that the Division remove the monthly flyash handling limitation. The Division has removed the monthly limitation since it only applied for the first 12 months of operation.

The 30 day rolling SO_2 emission limitation from construction permit 10EP325 was not included in the operating permit. The limit was originally added to the permit in order to assure the facility was not subject to a BART analysis. In lieu of this limitation, the more stringent reasonable progress determinations from Colorado Regulation No. 3, Part F were included in the operating permit.

CSU requested an alternate NO_X BACT limit for the simple cycle combustion turbines of 100 ppmvd at 15% O_2, on a 1-hour average for periods of combustion tuning and testing. A modeling analysis was not conducted for this scenario. See March 1, 2011 EPA Memorandum from Tyler Fox to Regional Air Division Directors, “Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard”, in which EPA asserts that “existing modeling guidelines provide sufficient discretion for reviewing authorities to exclude certain types of intermittent emissions from compliance demonstrations”. Combustion tuning and testing for 90 hours/year qualifies as an intermittent emissions source for which the guidance does not support a modeling analysis. In accordance with the EPA guidance, the source is required to restrict combusting tuning and testing operations to meteorologically favorable hours.

CSU submitted a modification to their fuel sampling plan for Division review. This plan has been approved by the Division. The plan may be modified by CSU upon request from the Division and may be revised upon request by the permittee. Revisions to these plans are subject to Division approval, but do not typically require permit reopening.

CSU submitted information to update their SO_2 and NO_X emission allowances under the Acid Rain program. These have been updated in Section III.

CSU requested clarification on the use of coal/woody biomass as fuel in B001. In accordance with PSD regulations, the use of this alternative fuel is not considered a modification since the unit was capable of accommodating the fuel prior to January 6, 1975. The operating permit was revised to include language regarding the use of coal/woody biomass as fuel in B001.

CAM

CSU identified the main boiler (Unit B001) as being subject to CAM. Controlled emissions of PM exceeds the major source level and this unit uses emission controls (baghouse for PM) to meet its PM emission limitations.

Unit B001 is subject to SO_2 and NO_X emission limitations under the Acid Rain Program (Section III of the current permit). Pursuant to 40 CFR Part 64 § 64.2(b)(1)(iii), the CAM requirements do not apply to Acid Rain Program emission limitations. B001 is also subject to SO_2 and NO_X emission limitations under the Regional Haze requirements in Colorado Regulation No. 3, Part F. However, pursuant to 40 CFR Part 64 § 64.2(b)(1)(iv), the CAM requirements do not apply to emission limits for which a continuous compliance demonstration method is required.

CAM does apply to Unit B001 with respect to the PM emission limitations. Note that although the unit is subject to opacity limits, they are not emission limitations subject to CAM requirements. The source submitted a CAM plan with their renewal application. In their CAM plan, the source proposed visible emissions, pressure differential and a daily inspection as indicators. For visible emissions, excursions are identified as an opacity value exceeding 10%. For pressure differential, an excursion is defined as any pressure differential reading outside the established range for 24 hours or longer.

The Division has reviewed the CAM plan submitted and while we accept the plan in part, we consider that the following changes to the plan are necessary.

Visible Emissions

Based on the relationship between particulate matter in a flue gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased. An increase in opacity, defined as an opacity reading greater than 10% is a possible indication that a bag has failed. During normal operations with no bag failures, opacity emissions will be below 10%. The Division accepts the indicator range of 10% opacity and will include this in the permit.

Pressure Differential

The pressure differential across a baghouse can be indicative of problems with the baghouse operations, such as broken bags, bad seals, plugged ash hopper or plugged ash line. A high pressure differential can be an indication of plugged bags and a low pressure differential can be an indication of broken bags, both of which would affect the performance of the baghouse. The pressure differential indicator range was chosen based on operating experience and good operational practices.

The Division has determined, based on past experience, that an increase or decrease in the pressure differential from the normal level at a specific operating load is not necessarily considered an indicator of decreased baghouse performance by itself. However, an increase or decrease in the pressure differential from the normal level, accompanied by a sustained increase in opacity is an indication of potential baghouse problems.

Since the normal pressure differential is specific to load and cannot be easily defined and because pressure differential by itself is not necessarily an indicator of potential problems with the baghouse, the Division will not include pressure differential in the CAM plan as an indicator. Therefore, the opacity monitoring that the Division is including in the CAM plan is appropriate for CAM and the Division does not believe that it is necessary to include pressure differential as an additional indicator.

Daily Inspection

The daily inspections of the mechanical operations of the baghouse will alert the plant operators of any potential failures prior to a significant increase in visible emissions. Inspection on a daily basis for the presence of a mechanical or operational problem will provide a means to detect possible problems before they develop into excess emissions. The Division defined an excursion as detection of a mechanical or operational problem, or failure to perform the inspection for two consecutive days.

In general, the CAM plan has been included in Appendix G of the permit as submitted, except that the corrections indicated above have been made to the plan and some language has been omitted, revised or relocated in order to streamline the plan.

FRPP Turbines

The requirements applicable to the combined cycle combustion turbines located at FRPP, previously owned by Front Range Power Authority, were incorporated into the operating permit. Initial approval of modification 1 of construction permit 99EP0851 was issued September 25, 2002. A final approval construction permit has not been issued. Under the provisions of Colorado Regulation No. 3, Part C, Section V.A.2, the Division will not issue a final approval construction permit and is allowing the initial approval construction permit to continue in full force and effect and will consider the Responsible Official certification submitted with first semi-annual monitoring and deviation report required by this operating permit to serve as the demonstration required pursuant to Colorado Regulation No. 3, Part B, Section III.G.2.

S001: One (1) General Electric Model 7241FA, natural gas fired, combined cycle turbine for electric power generation. The gas turbine is rated at a heat input of 1,775 MMBtu/hr, and site output rated at 158 MW, depending on ambient conditions and the duct burner is rated at a heat input of 325 MMBtu/hr, and contributes to a generation of up to approximately 50 MW. This turbine is equipped with an advanced low NO_X combustion system.

S002: One (1) General Electric Model 7241FA, natural gas fired, combined cycle turbine for electric power generation. The gas turbine is rated at a heat input of 1,775 MMBtu/hr, and site output rated at 158 MW, depending on ambient conditions, and the duct burner is rated at a heat input of 325 MMBtu/hr, and contributes to a generation of up to approximately 50 MW. This turbine is equipped with an advanced low NO_X combustion system.

Applicable Requirements: The appropriate applicable requirements from the initial approval construction permit 99EP0851 have been incorporated into the permit as follows. The specific requirements are intended to apply to each turbine unless otherwise noted.

- *All previous versions of this permit are canceled upon issuance of this permit (Condition 1).*

  This is not a requirement for the source and pertains to the construction permit only and was not included in the operating permit.

- *Emission of Any Single Hazardous Air Pollutant shall not exceed eight (8) tons per year. Emissions of total of All Hazardous Air Pollutants shall not exceed twenty (20) tons per year. These limits are being accepted to limit the emissions to minor source levels from the turbines. These limits are applicable to the aggregate emissions from the gas turbines installed as one project, and covered under this permit. (Condition 2)*

  While the turbines alone do not constitute a major source of HAP emissions, the FRPP turbines are considered a single source with the equipment located at the Nixon plant and are therefore considered to be major for HAPs. As such, the synthetic minor HAP limits were removed.

- *Visible emissions shall not exceed twenty percent (20%) opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes. Opacity shall be measured by EPA Method 9. (Reference: Regulation 1, Section II. A. 1. & 4.) (Condition 3)*

  The Reg. 1 opacity limit was included in the operating permit. Compliance with the opacity standard is presumed given the turbine fires pipeline quality natural gas only.

- *The manufacturer, model number and serial number of the subject equipment shall be provided to the Division prior to Final Approval. (Reference: Reg. 3, Part B, IV. E.) (Condition 4)*

  As previously discussed, a final approval permit will not be issued. The information requested by this condition has been provided to the Division. As such, this requirement was not included in the operating permit.

- *AIRS ID numbers shall be marked on the subject equipment for ease of identification. (Reference: Reg. 3, Part B, IV. E.) (State only enforceable) (Condition 5)*

  This is a construction permit only requirement and was not included in the operating permit.

- *The emission sources covered under this permit are subject to Prevention* *of Significant Deterioration (PSD) provisions, and Best Available Control Technology (BACT) shall be applied for control of Carbon Monoxide, Particulate Matter, and Particulate Matter less than 10 micrometers in aerodynamic diameter. The following BACT determinations shall be complied with:*

<u>Carbon Monoxide:</u> Good combustion control practices shall be applied to minimize emissions of Carbon Monoxide. During normal operation, concentration of Carbon Monoxide in the exhaust from the combined-cycle combustion turbines shall not exceed 25 parts per million, volume, dry basis, at 15 % Oxygen, (hourly average). During Startup and Shutdown concentration of Carbon Monoxide shall not exceed 1,210 parts per million, hourly average, volume, dry basis, at 15 % Oxygen. This is a conservatively high concentration, and shall be adjusted after sufficient data becomes available.

Startup is defined as the period from the push of the start button until 20 minutes after combustion is switched to Mode 6.

Shutdown is defined as the period from leaving Mode 6 until the gas valve is closed.

<u>Particulate Matter and Particulate Matter less than 10 micrometers in aerodynamic diameter (PM-10):</u> Emissions of Particulate Matter and PM-10 shall be minimized by using pipeline quality natural gas, and by application of good combustion control practices.

"Good combustion control practices" constitute monitoring and control of several operating parameters. All relevant parameters and their optimal operating ranges for various combustion devices shall be identified, and included in the required operation and maintenance plan. (Condition 6)

The BACT limits were included in the permit. The startup shutdown concentration limit was reevaluated, as sufficient data has become available. Based on historical CEMS data, it was determined that the original 1,210 ppmv limit continues to be appropriate for startup and shutdown periods.

- *Prevention of Significant Deterioration (PSD) requirements shall apply to this source at any such time that this source becomes major solely by virtue of a relaxation in any permit condition. Any relaxation that increases the potential to emit above the applicable PSD threshold will require a full PSD review of the source as though construction had not yet commenced on the source. The source shall not exceed the PSD threshold until a PSD permit is granted. This is applicable to all pollutants for which a PSD review has not been addressed in this permit. (Reference: Reg. 3, Part B, IV. D. 3. b. (iv))(Condition 7)*

  This condition was not included in the operating permit since no actual requirements apply. The PSD status of the source is discussed in Section I, Condition 3 of the permit.

- *This source shall be limited to a maximum fuel use rate as listed below and all other activities, operational rates and numbers of equipment as stated in the application. Monthly records of the actual consumption rate shall be maintained by the applicant and made available to the Division for inspection upon request. (Reference: Regulation 3, Part B, III. A. 4.)*

  Total heat input through pipeline quality natural gas into the two combined-cycle combustion turbines shall not exceed 2,900,000 million BTU per month, and 31,781,280 million BTU per year.

  During the first twelve (12) months of operation, compliance with both the monthly and yearly consumption limitations shall be required. After the first twelve (12) months of operation, compliance with only the yearly limitation shall be required. Compliance with the yearly consumption limits shall be determined on a rolling twelve (12) month total.(Condition 8)

  The actual maximum heat input to the gas turbines and associated duct burners was observed to be higher than originally anticipated during the initial permit review. The source requested that the heat input limits in the permit be increased to 3,124,800 MMBtu/month and 33,600,000 MMBtu/year. The annual limit was included in the operating permit. The monthly limit was not included in the permit in accordance with PS-Memo 98-3.

- *Total emissions of air pollutants from the two combined-cycle combustion turbines shall not exceed the following limitations (as calculated in the Division's preliminary analysis):*

o *Particulate Matter:*	*256.2 tons per year.*
o *PM10 (Particulate Matter<10 μm):*	*256.2 tons per year.*
o *Sulfur Dioxide:*	*9.9 tons per year.*
o *Nitrogen Oxides:*	*632.6 tons per year.*
o *Volatile Organic Compounds:*	*30.0 tons per year.*
o *Carbon Monoxide:*	*390.0 tons during the break-in.* *411.8 tons/yr after the break-in.*

  Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve month total is calculated based on the previous twelve months' data. The permit holder shall calculate monthly emissions and keep a compliance record on site for Division review. (Reference: Regulation 3, Part B, III. A. 4) (Condition 9)

  The annual emission limitations for the turbines have been included in the operating permit. The break-in period was not defined by the construction permit. However, the Division had agreed to consider the CO break-in period the six months following the date of first operation. This period has since passed and the break-in limit is no longer applicable and was not included in the operating permit. The sulfur dioxide limitation was revised to reflect a more accurate calculation of emissions based on Appendix D emission factors.

- *Prior to final approval being issued, the applicant shall submit to the Division for approval an operating and maintenance plan for all control equipment and control practices, and a proposed record keeping format that will outline how the applicant will maintain compliance on an ongoing basis with the requirements of this permit. (Reference: Reg. 3, Part B, IV. B. 2) (Condition 10)*

  The appropriate provisions from the operating and maintenance plan have been included in the operating permit.

- *For each combined-cycle turbine, a continuous emission monitoring system (CEM) shall be installed, calibrated, certified, maintained, and operated to measure and record: (Condition 11)*

  - *Hourly concentration of Nitrogen Oxides in the turbine exhaust, ppmvd, corrected to 15 % Oxygen;*
  - *Hourly concentration of Oxygen in the turbine exhausts, percent;*
  - *Emissions of Nitrogen Oxides, tons per month, and tons per rolling 12-month periods;*
  - *Hourly concentration of Carbon Monoxide in the turbine exhaust, ppmvd, corrected to 15 % Oxygen;*
  - *Emissions of Carbon Monoxide, tons per month, and tons per rolling 12-month periods;*
  - *Fuel flow rate, SCF per hour for natural gas*

  Quality assurance / quality control shall conform to:
  - *40 CFR Part 60, Appendix F, and Subpart A,*
  - *40 CFR Part 75, and*
  - *Division approved plan.*

  The requirement to install and operate a certified CEMS was included in the permit. The units of measurement were adjusted to correspond with the applicable emissions standards.

- *Within one hundred and eighty days (180) after commencement of operation, compliance with the conditions contained on this permit shall be demonstrated to the Division. It is the permittee's responsibility to self certify compliance with the conditions. Failure to demonstrate compliance within 180 days may result in revocation of the permit. (Condition 12)*

  Self-certification was received for these turbines on October 31, 2003, therefore this requirement was not included in the operating permit.

- *Source compliance tests shall be conducted, on the two combined-cycle gas turbines to measure the emission rate(s) for the pollutants listed below in order to, show compliance with the emission limits / standards for pollutants not continuously monitored, verify and certify the continuous emission monitoring systems, and demonstrate that Maximum Achievable Control Technology (MACT) is not triggered. The test protocol must be in accordance with the requirements of the Air Pollution Control Division Compliance test Manual and shall be submitted to the Division for review and approval at least thirty (30) days prior to testing. No compliance test shall be conducted without prior approval from the Division. Any stack test conducted to show compliance with a monthly or annual emission limitation shall have the results projected up to the monthly or annual averaging time by multiplying the test results by the allowable number of operating hours for that averaging time (Reference: Regulation 3, Part B. IV. H. 3) (Condition 13)*

  - *Particulate Matter using EPA approved methods.*
  - *Sulfur Dioxide using EPA approved methods.*
  - *Oxides of Nitrogen using EPA approved methods.*
  - *Volatile Organic Compounds, and speciated for hazardous air pollutants listed under Notes to Permit Holder, using EPA approved methods.*
  - *Carbon Monoxide using EPA approved methods.*

  The performance test required by this condition has already been conducted, therefore this requirement was not included in the operating permit.

- *The emission sources are subject to Regulation No. 6 - Standards of Performance for New Stationary Sources, including, but not limited to, the following: (Condition 14)*

  ***Turbines** referenced under AIRS IDs: 012 and 013 are subject to Subpart GG - Standards of Performance for Stationary Gas Turbines:*

  - *Concentration of Nitrogen Oxides in the turbine exhaust shall not be in excess of 111 parts per million, volume, dry basis, at 15 % Oxygen.*

  - *Concentration of Sulfur Dioxide in the turbine exhaust shall not be in excess of 150 parts per million, volume, dry basis, at 15 % Oxygen, or the fuel combusted shall not contain sulfur in excess of 0.8 % by weight.*

  ***Duct burners** referenced under AIRS IDs: 012 and 013 are subject to Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is commenced After September 18, 1978:*

- *Emissions of particulate matter shall not be in excess of 0.03 pound per million BTU heat input.*
- *Gases discharged into the atmosphere shall not exhibit greater than 20 % opacity (6-minute average), except for one 6-minute period per hour of not more than 27 % opacity.*
- *Gases discharged into the atmosphere shall contain less than 0.2 pound Sulfur Dioxide per million BTU heat input.*
- *Gases discharged into the atmosphere shall not contain Nitrogen Oxides (expressed as NO_2) in excess of 200 nanograms per joule (1.6 pounds per megawatt-hour) gross energy output.*

***Turbines** referenced under AIRS IDs: 012 and 013 are subject to Section II - Standards of Performance for New Fuel-Burning Equipment,*

- *C - Standard for Particulate Matter. Discharge into the atmosphere shall not exhibit greater than 20 % opacity. Particulate matter discharged into the atmosphere shall not be in excess of the rate calculated by the equation:*

  $$PE = 0.5\,(FI)^{-0.26}$$

  Where: PE is the allowable particulate matter emissions in pounds per million BTU heat input.

  FI is the fuel input in million BTU per hour.

- *D - Standard for Sulfur Dioxide, 3 - Combustion Turbines: Sulfur Dioxide discharged into the atmosphere shall not be in excess of 0.35 pound per million BTU heat input.*

In addition, the requirements of Regulation No. 6, Part A, Subpart A, General Provisions, apply.

The applicable requirements from NSPS Subparts GG, Da, and Colorado Regulation No. 6, Part B were included in the operating permit.

- *APEN reporting requirements (Condition 15).*

  The APEN reporting requirements are included in Section IV (General Conditions) Condition 22.e of the operating permit.

Emission Factors: Emissions of NO_X and CO from these turbines are calculated using the CEMS required by the permit. Emissions of PM, PM_{10}, and VOC are calculated using emission factors derived from stack test data and the heat input from CEMS. SO_2 emissions are calculated using the 40 CFR Part 75 Appendix D emission factor and the heat input from CEMS.

Monitoring Plan: The turbines are equipped with CEMS to monitor compliance with the NO_X and CO emission limitations. Compliance with the short-term SO_2 and particulate emissions limitations and opacity standards is assumed provided natural gas is the only fuel used in the turbines. VOC emissions will be calculated on a monthly basis and compliance with the annual emissions limitation will be monitored using a 12 month rolling total. The source is also required to calculate natural gas consumption on a monthly basis to monitor compliance with the fuel use limitation.

Other Modifications

In addition to the requested modifications, the Division has included changes to make the permit more consistent with recently issued permits, included comments made by EPA on other Operating Permits, as well as corrected errors or omissions identified during inspections and/or discrepancies identified during review of this renewal.

These changes are as follows:

Page following the cover page

- Added language specifying that the semi-annual reports and compliance certifications are due in the Division's office and that postmarks cannot be used for purposes of determining the timely receipt of such reports/certifications. Materials received are dated upon entry to the Division's mail room.

Section I - General Activities and Summary

- Conditions 13 and 17 in Condition 1.4 were renumbered to 14 and 18 and Condition 21 in Condition 1.5 was renumbered to 22. The renumbering changes were necessary due to the addition of the Common Provisions requirements in the General Conditions of the permit. In addition, General Condition 3.g was added as a state-only requirement.

- Changes to the condition numbering were made to be consistent with other recently issued permits.

- Minor language changes were made to Condition 3.1 to more appropriately reflect the status of the source with respect to PSD.

Section II - Specific Permit Terms

- The tables and permit language in Section II have received format and language changes to match recently issued permits. This has not altered the requirements of the specific conditions.

Section II.1 – B001

- The particulate matter stack testing requirements have been moved from the previous permit location (Condition 1.5.5) to Condition 9. The current stack testing language was included to be consistent with recently issued permits. The retesting requirements have also been modified to require retesting within a certain time frame (annual, 3 years, 5 years) instead of basing retesting upon permit terms as was the case with the original permit.

- The following language was removed from Condition 1.1.3: “Spikes in instantaneous opacity observed by boiler operators during the baghouse cleaning cycle shall be cause for investigation”. The intent of the requirement has now been replaced with the CAM plan. As such, this language is no longer necessary.

- The SO_2 limit from Subpart D was streamlined from the permit. Compliance with this requirement is presumed given compliance with Colorado Regulation No. 1, Section VI.A.3 as listed in Condition 1.4 of the permit.

- The Division has removed Condition 1.7.8 of the original permit since startup of the FRPP turbines has occurred.

- The Division added the following language to Condition 1.8.1 of the renewal permit to identify how fuel usage shall be tracked: “Fuel usage shall be determined using belt scales, vendor receipts, or corporate records as necessary.”

- The Division added Condition 1.9 regarding fuel sampling in order to clarify the requirement.

- Since EPA promulgated a more stringent national ambient air quality standard for lead in 2008, the Division removed the state-only lead requirement from Colorado Regulation No. 8, Part C. Therefore, the requirement from Condition 1.11 was removed from the operating permit. Note that the lead NAAQS will not be included in the permit as NAAQS are not considered applicable requirements and as such are not included in Title V permits.

- The Regional Haze requirements from Regulation No. 3, Part F were added to the permit.

- The state-only mercury rule requirements for Low Emitters were included in the permit.

<u>Section II.2 – B002</u>

- As mentioned previously, CSU requested removal of the allowance to use specification used oil in the boilers. The Division removed specification used oil from the fuel usage limitation (Condition 2.2), and the specification used oil emission factors from the summary table.

- The natural gas particulate matter emission factors have changed from the previous permit. The revised emission factors (7.6 lb/MMscf) have been included in the summary table. The emission factor was previously listed as 1.9 lb/MMscf.

- All the emission limitations have been revised due to the removal of specification used oil. The Division determined the maximum emissions considering the use of natural gas or No. 2 distillate oil and the existing MMBtu annual limitation. This reduced the emission limitations of some pollutants.

- As discussed above, the provisions of the Boiler MACT (Subpart DDDDD) were added to the operating permit.

<u>Section II.7 – S003 & S004</u>

- The Division removed Condition 7.6.6 of the previous permit regarding changes in fuel supply. The condition was confusing and it is not anticipated that there would be a change in fuel supply that would cause any exceedance in permit limitations.

- The Division removed Condition 7.12 of the previous permit regarding pre and post construction monitoring for ozone. This is not an applicable requirement. Should a PSD modification regarding ozone occur in the future, the Division will include appropriate PSD monitoring requirements.

- The Division removed Condition 7.13 of the previous permit regarding CO and VOC emissions remaining below the PSD significance thresholds. This condition is not required since the permit already contains appropriate annual limitations on these pollutants.

- The CEMS requirements in Condition 7.9 were slightly modified to include the appropriate units in which the CEMS should record data.

- The Division updated the NSPS GG requirements to allow monitoring the natural gas sulfur content using contracts and tariff sheets (Condition 7.4.2.3).

- The Division streamlined out the Regulation No. 6 SO_2 limitation of 0.35 lb/mmBtu (previously Condition 7.8.2) and included the Regulation No. 1 SO_2 limitation of 0.35 lb/mmBtu. The limitations are identical. However, the Regulation No. 6 limitation was state-only, thus, the Division streamlined it out.

- The Division included the VOC compliance emission factor in Summary Table 7: 9.8553 lb/MMscf.

- The Division included the Regulation No. 1 PM emission limitation in Condition 7.2.2. This was not included in the previous permit. A one-time calculation is sufficient to demonstrate compliance with this limitation.

- The Division added Condition 7.13 which requires CSU to demonstrate that the natural gas used meets the definition of pipeline quality natural gas as defined in 40 CFR Part 72.

- The Division added Condition 7.15 which clarifies that these units are subject to the Title V Acid Rain Requirements.

Section II – Other

- The Division modified the CEMS/COMS requirements in Condition 8.5 to include the 40 CFR Part 60 Subpart A Reporting and Recordkeeping requirements instead of the Regulation No. 1 requirements listed in the original Operating Permit. The Regulation No. 1 requirements have been streamlined out of the permit and are listed in Section IV.3.

- The fuel sampling requirements for coal have been modified. It appears the Division has reviewed and approved the current coal monitoring plan. This plan may be modified in the future by CSU if requested by the Division, and may be revised upon request by the permittee. Revisions to these plans are subject to Division approval, but typically do not require permit reopening.

- The fuel sampling conditions for fuel oil and natural gas have been removed from the permit. The previous language outlined what needed to be included in the fuel sampling plans. At this point, it appears that both the fuel oil and natural gas sampling plans have been submitted by CSU and approved by the Division. The requirement to follow these plans is still included in the permit conditions located under each subject unit.

- The emergency generators, previously listed as insignificant activity, were moved to the body of the permit and the applicable requirements from NESHAP Subpart ZZZZ for reciprocating internal combustion engines were added.

Section III – Acid Rain Requirements

- The Division moved the requirements to Section III.

- The Division updated the designated representative.

- The Division updated the SO_2 allowances and NO_X limits for the Renewal permit term.

- The NO_X Early Election language has been removed

- The Division updated the Reporting Requirements to remove the requirement to submit a copy of any revised certificate of representation to the Division, the requirement to submit the annual reports & compliance certification and quarterly compliance certifications to the Division.

Section IV – Permit Shield

- The citation in the permit shield was corrected.

Section V - General Conditions

- The general conditions were updated with the most current version (5/22/2012).

Appendices

- The list of insignificant activities from the Front Range Power Plant Title V Application was incorporated in the list of insignificant activities in Appendix A.

- Appendix B & C have been updated to the current version (02/20/2007). The requirement to determine if data was continuous has been removed from Appendix C.

- The table in Appendix F was cleared.

- The mailing address of EPA was updated in Appendix D.

- As discussed above, the Division removed the fuel oil monitoring plan requirements and coal sampling requirements. These plans have been submitted and approved.

- The Division removed the revegetation plan and will maintain it within the Division files.

- The Division removed the Title IV Phase II Application. This does not need to be included in the permit.